

MODELING OF CALCITE SCALING IN A GEOTHERMAL WELL

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ABSTRACT

In this paper, we describe the construction of a relatively simple well model by means of the TOUGHREACT code. We used a kinetic approach to compute calcite precipitation/scaling in two producing geothermal wells at the geothermal field of Ahuachapan in El Salvador. The model succeeded in accurately computing the depth of calcite encrustation, and shows a strict correlation between scaling and flashing. For this computation, we used only the major chemical composition of the water, a kinetic model for calcite deposition, and two fixed pressure (infinite-volume gridblocks) boundary conditions for the well-head (fluid extraction) and reservoir.

INTRODUCTION

Rock-fluid interaction studies suggest that mineral dissolution and precipitation effects have a major impact on the long-term performance of a geothermal well. Since it is common to have geothermal wells drilled in carbonate formations, or formations with significant carbonate contents, we decided to investigate the precipitation and dissolution of calcite in geothermal wells. Calcite relates to the carbon dioxide behavior, as governed by boiling, dilution, and condensation processes (Simmons and Christenson, 1994).

Calcite dissolution gradually decreases along the flow path from the recharge inflow of fresh water toward the extraction well, whereas calcite

precipitation occurs within the extraction well. The deposition of calcite is mainly related to two effects: (1) evaporation of the brine, which leads to an increase in dissolved calcium and carbonate concentrations, and (2) forced CO₂ exsolution during boiling, which leads to an increase in the saturation index of calcite.

We considered scaling processes in the extraction well from an infinite-extent reservoir, where vaporization of the solution occurs within the well because of fluid extraction at constant pressure. The calcite sealing mechanism, which has been studied by several authors using different approaches, increases the complexity of the sealing model itself. The first approach is a stationary equilibrium model (e.g., Moller et al., 1998) where sealing is obtained by defining the CO₂ exsolution point; another approach (and further improvement) is a reactive transport model (e.g. Xu et al., 2004) used to simulate fluid production and calcite deposition/ dissolution processes from a well located at the center of a 2D radial carbonate reservoir.

In this study, we present a reactive transport model that takes into account the kinetics of dissolution/precipitation of carbonates, with a significant amount of carbonate minerals present in the modeled system. The model is based on data from the geothermal field at Ahuachapan, El Salvador, where calcite makes up ~30% of the entire rock.

The chemical composition of modeled reservoir water was obtained by using a brine with measured NaCl content, and calcium and carbonate concentrations computed assuming CO₂-brine-rock equilibrium in a 2D radial carbonate reservoir. Because initial equilibrium is assumed, the resulting reservoir fluid composition is independent from the amount of carbonates minerals as long as these phases remain present after reaction.

For the well-scaling model, we used an upward linear model, with two infinite-volume grid-blocks simulating the extraction pressure condition (measured in dynamic regime at the well-head) and the reservoir pressure condition (measured in dynamic regime at the well-bottom), and a well discretized with a cell length of 0.5 m up to the total well depth.

The well-scaling model, computed by means of the TOUGHREACT software package, is then calibrated by varying the CO₂ partial pressure in the reservoir in order to match the pH measured at the well-head. After calibration, the depth of the calcite precipitation level is compared with the scale depth measured during well-cleaning operations; unfortunately, it was not possible to compare the predicted amount of precipitated calcite with measured amounts because these data were not available.

This procedure was applied to the geothermal wells AH33A-B and AH35A-B (Fig. 1) in Ahuachapan, El Salvador, which are known to be affected by calcite scaling, mainly in the southern part of the geothermal field, due to the relatively high calcite content in the host rocks.

Increasing the model complexity requires a more complete input thermodynamic database and a more detailed knowledge of the reservoir conditions. In this study, we present a real but simplified case in order to show how a relatively simple model may be able to forecast calcite scaling with reasonable accuracy.

GEOHERMAL FIELD SETTINGS

The Ahuachapán geothermal field (Fig. 1) is located in the western part of El Salvador, some 20 km from the border with Guatemala, 40 km from the Pacific Ocean, and 120 km from San

Salvador, the capital city. The geothermal area is about 100 km² and is associated with the andesitic stratovolcano Laguna Verde. The system is located between the southern flank of the central salvadorean graben median trough and the northwestern sector of the Cerro Laguna Verde Volcanic group. This group constitutes a complex extrusive structure developed during the Quaternary near the Pliocene tectonic block of Tacuba-Apaneca, the regional faults of which have controlled (first) the sinking of the graben and (subsequently) the extrusion of volcanic products. This complex structural location favors deep hot fluid ascent through a marginal set of faults and further lateral fluid migration along a NW-SE oriented transversal fault system.

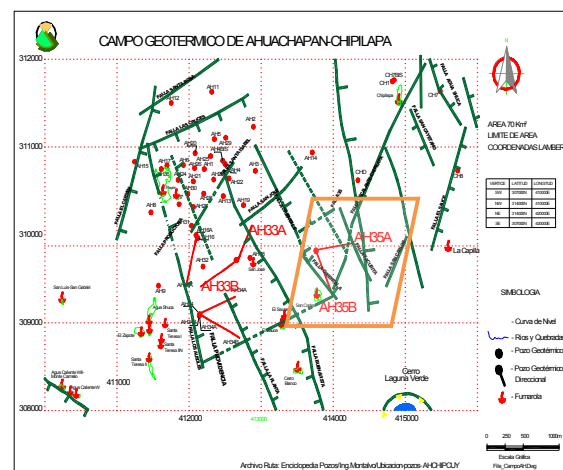


Figure 1. Wells location in the Ahuachapan geothermal field. The current investigation was carried out at AH35A - B and AH33A-B wells (within the rectangle).

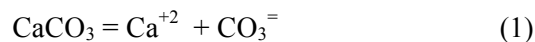
At present, the Ahuachapán geothermal field has 16 production wells generating around 79 Mwe (gross), representing 12% of the total electricity consumption in the country. Production wells AH-33B and AH-35A, located in the SSE part of the field, requires a chemical antiscalant dosing system to prevent calcite scaling.

The Ahuachapan waters are medium to high saline waters, similar to those found at many other geothermal fields. Such waters are characterized by near-neutral pH, high calcium concentrations, and relatively low bicarbonate concentrations. The waters sampled in the southern part of the field show different

chemical compositions, and the well-head pH is higher for wells affected by scaling, like AH-35B. This seems to point to an increased pH due to CO₂ exsolution during fluid upraising.

MODEL SETTINGS

The calcite scaling potential is determined by the concentrations of calcium and carbonate species, which dictate the calcite solubility product:



At most geothermal reservoirs calcite is present in the wall-rock, and the waters are at or close to calcite saturation. Waters become supersaturated with respect to calcite when they flow up a well, boil, and lose CO₂, shifting reaction (2) to the right:



To model the well flow, which should take into account both the water boiling and the CO₂ exsolution, we must know the reservoir CO₂ partial pressure. Boiling-degassing is not a linear process, involving an irreversible step (i.e., calcite precipitation). We started by constructing an equilibrium model of 1 m³ at reservoir conditions (10% porosity, 235°C, 66 bar, 23% calcite) and computed the water compositions resulting from equilibration with CO₂ at various P_{CO_2} values. The resulting water compositions are used in the infinite-volume griddblock representing the reservoir in the well-scaling model. The well bore is simulated by means of the TOUGHREACT code with equation of state EOS2, using griddblocks (corresponding to a 7-inch liner) with a height of 0.5 m along the well axis. For computation, the effective well depth is used, rather than actual length, in order to preserve a linear pressure gradient with depth. The extraction at the well top is modeled with an infinite-volume griddblock at a constant pressure, i.e., well-head pressure.

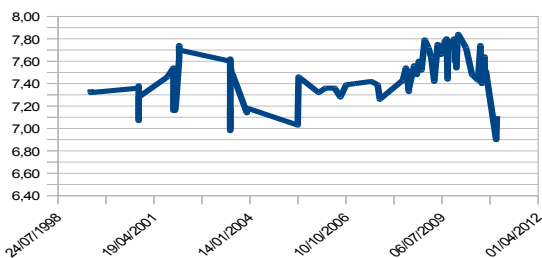


Figure 2. Measured pH time series at the AH35B well

The water salinity is ~0.4 M NaCl; using these data, the P_{CO_2} value is adjusted in order to match the 7.2 pH (recent pH average, Fig. 2) at the well head, resulting in a 10 bar P_{CO_2} over 66 bar total reservoir pressure.

We use these conditions to set up the reservoir fluid with respect to carbonate species and CO_{2(g)}, and to model fluid rising in similar wells, i.e., AH35A-B and AH33A-B.

MODEL VALIDATION

In order to validate the model, we compared the results of the model with the available data. Unfortunately the only available data are the depth of calcite encrustation found during the cleaning of the AH33B and AH35A wells; no quantitative information is available on calcite amounts. The AH33B and AH35A wells have similar well-head pressures, 6.8 and 6.48 bar, respectively. Fig. 3 shows how the encrustation found at 714–797 m depth relates with water flashing (beginning at 842.8 m depth).

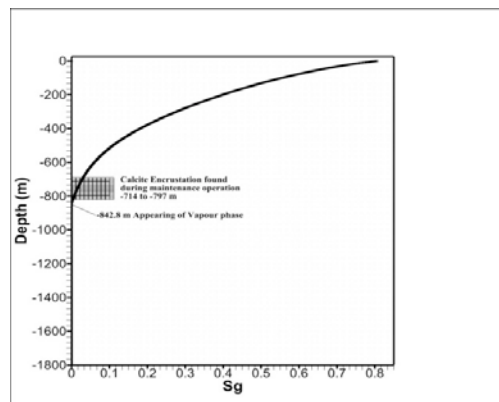


Figure 3. Gas saturation (Sg) vs depth in well AH35A

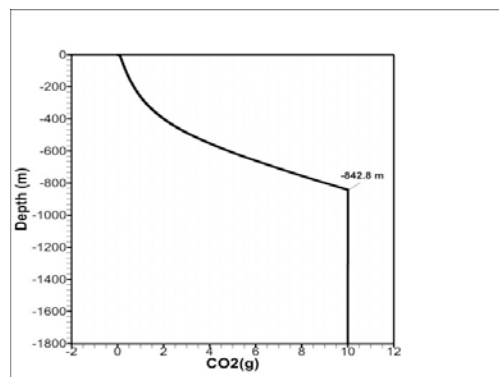


Figure 4. CO_{2(g)} partial pressure (bar) vs depth profile

At the same depth, the CO₂ partial pressure decrease and pH increase begin, as shown in Figs. 4–5.

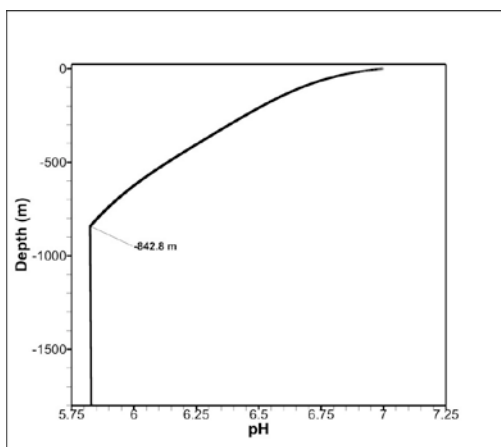


Figure 5. pH vs depth profile

The same modeling procedure was followed for the AH33B well. Fig. 6 shows the location of calcite encrustation (790-841 m depth) with respect to water flashing (beginning at 843.8 m depth). In these cases, there is very good agreement among water flashing and calcite precipitation depth.

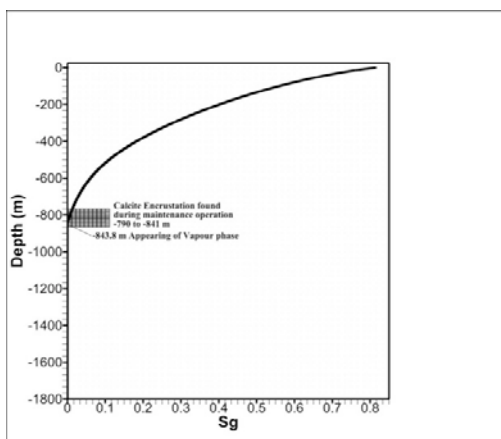


Figure 6. Gas saturation (Sg) vs depth in well AH33B

In this kind of model, the saturation index of calcite starts from zero in the reservoir (due to the imposed equilibrium condition) and maintains a very small value (around or slightly higher than zero) over the entire model. The main role in controlling calcite deposition is played by both CO_{2(g)} exsolution and solution concentration due to boiling, but these two phenomena are superimposed, making it

impossible to isolate the effect of either one alone. Since calibrating the amount and geometry of deposited calcite is not possible, we do not have any other comment apart from the fact that we used a “guessed” geometric deposition surface corresponding to a 45-micron crystal size, corresponding to the commercial steel-pipe roughness.

WELL MANAGERMENTS

Given the strict relation of calcite precipitation with water flashing, and knowing that changing the well-head pressure moves the flash point up or down within the well, we constructed a graph of well-head pressure versus flash point depth, while keeping reservoir conditions constant (Figure 7).

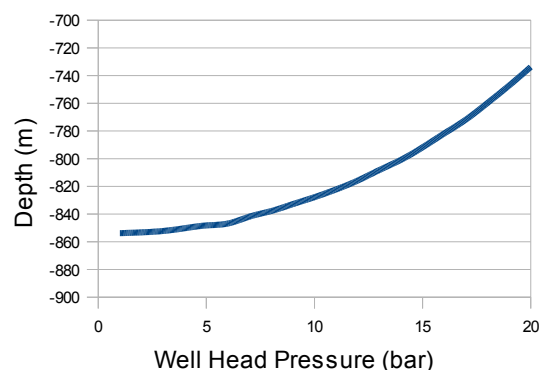


Figure 7. Computed flash point depth vs well-head pressure

Within a reasonable range of well head pressures (2-20 bar), the flash-point depth varies only from 740 to 850 m depth; thus, the effect of “diluting” the encrustation by regulating the well-head pressure (and reducing the cleaning operation frequency) is very limited.

The solution used here was to add an anti-scalant to the well fluid below the flashing point, at a depth around 1000 m in the liquid phase. In the AH35A and AH33B wells, the anti-scalant was injected at -975 and -1050 m, respectively.

It is also useful to evaluate the flash-point variation while keeping constant the extraction pressure and varying the reservoir pressure, to check how the recharge-exploitation of the reservoir affect the flash point (and encrustation) position.

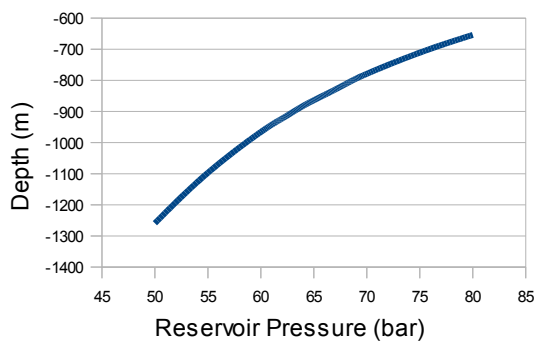


Figure 8. Flash point depth vs reservoir pressure

Fig. 8 shows that the flash-point position is very sensitive to the reservoir pressure, and that if the reservoir pressure decreases too much, the flash point will enter the reservoir, with the risk of sealing it.

CONCLUSIONS

Briefly summarizing our findings, we conclude that (1) calcite scaling can be modeled by using a simple (kinetic) model considering only the carbonate species, (2) we must use the effective well length in order to preserve a linear pressure gradient, (3) flash-point control by means of regulating well-head pressure may not be very effective in mitigating calcite encrustation, and (4) reservoir conditions play a significant role in regulating both flash point and calcite encrustation depth.

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